TAYLOR NGL Limited Partnership

2003 Annual Report

Corporate Profile

The Taylor NGL Limited Partnership (the Partnership or Taylor) trades on The Toronto Stock Exchange under the symbol TAY.UN. Taylor provides investors with a unique opportunity to participate in the energy business through the following interests:

- Ownership of Taylor Gas Liquids Limited Partnership that holds a majority interest in and operates the Younger Extraction Plant;
- Ownership of Joffre Gas Liquids Limited Partnership that holds a 50 percent interest in and operates the Joffre Extraction Plant; and
- Ownership of Taylor Gas Processing Limited Partnership, which owns a majority interest in and operates the [illegible] Complex.

Both the Younger and Joffre plants extract ethane, propane, butane and condensate, collectively known as natural gas liquids or NGLs, from natural gas. Taylor markets its share of Younger production through a long-term marketing arrangement with EnCana Corporation. At the Joffre Extraction Plant, the Partnership is selling its share of ethane production to NOVA Chemicals Corporation under a long-term marketing agreement and is selling the remainder of the NGL production into the Alberta market at prevailing prices.

The [illegible] Complex provides natural gas gathering and processing services to producers on a fee-for-service basis.

Taylor and the plants are administered by Taylor Management Company Inc., a privately-owned company, and its wholly-owned subsidiary Taylor Operations Company Inc.

Annual General Meeting

The Annual Meeting of the Taylor NGL Limited Partnership will be held on April 23, 2004, at [illegible] a.m. at the Metropolitan Centre, 333-4th Ave. S.W., Calgary, Alberta.

All unitholders are invited to attend. Those who are unable to attend are kindly requested to sign and return their proxies as soon as possible.

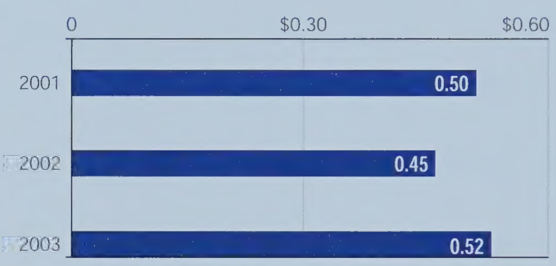
Contents

6. Letter To Unitholders
10. Operations Review
18. Management's Discussion & Analysis
34. Financial Statements
37. Notes to Financial Statements
48. Corporate Information
IBC. Officers and Directors

2003 was a pivotal year for Taylor.

Taylor's market capitalization grew by 160 percent and unitholders' total return was over 45 percent as two facilities were added.

Distributed Income ($ mm)



Distributed Income per Unit

We Commissioned Additional Assets

We built a grassroots gas processing facility at Joffre, Alberta that extracts natural gas liquids from the fuel gas that is consumed by NOVA Chemicals Corporation's neighbouring world-scale petrochemical facility.

We Acquired Additional Assets

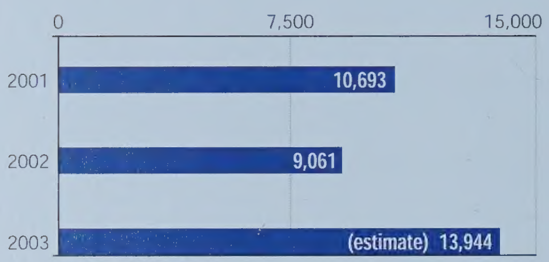
We purchased three interconnected natural gas processing plants – the RET Complex – which are located in a very active exploration and production region of Alberta.

We Added Value

Distributions per unit increased by more than 15 percent, confirming the value of the facilities added during the year. This growth was accomplished while reducing our long-term debt to 15 percent of enterprise value.

Taylor is poised for growth.

The natural gas industry is attracting a high level of investment. This means expansion and diversification opportunities for the Partnership.



Natural Gas Wells Drilled in Western Canada

AECO Natural Gas Price ($ per GJ)

Further Growth

Participants in the upstream, midstream and downstream sectors of the natural gas industry are continually evaluating their portfolio and asset mix. In the never-ending quest to optimize the deployment of corporate resources, companies acquire, divest and trade assets in a search to create value.

Taylor is Different

Taylor has access to development opportunities that can be attuned with one of our three core facilities – Younger, Joffre or RET. Taylor has a proven record of operational and construction capability. We can acquire assets knowing that, if necessary, we can change the operation to meet the standard required by income fund investors.

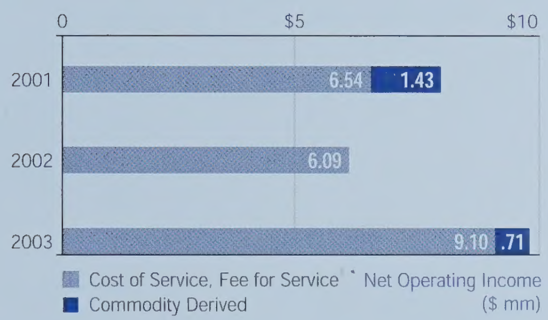
Acquire High-Quality Assets

Any new opportunity that is proposed by management is tested against Taylor's growth strategy:

- Target opportunities that are low-risk, have predictable cash flow and are long-life.
- Acquire assets that have upside and where Taylor can be the operator of the facilities and have a controlling interest.
- Grow in manageable steps and ensure smooth integration into current business activities.

Managing for Growth and Stability.

Taylor's goal is to diversify operating income by continuing to add to the current portfolio of cost-of-service and fee-for-service businesses.



Active Management

Taylor operates and has a controlling interest in each of its facilities. This means that management can continually optimize production strategies, control costs, and develop opportunities at the plants to ensure that each contributes a stable, long-term operating income stream to the Partnership.

Low-Risk Operating Income

Taylor has a diversified, low-risk operating income base from facilities with fixed payments and fee-for-service arrangements. Diversity results in stable operating income as each of the Partnership's assets is exposed to different and often offsetting risks.

Prudent Financial Structure

Financing of growth has two criteria: ensure distribution per unit growth and use debt conservatively. Taylor understands risk; exposure to foreign exchange risk has been mitigated with costless collar arrangements. Taylor has also managed the volatility of electrical power, a significant component of operating cost.

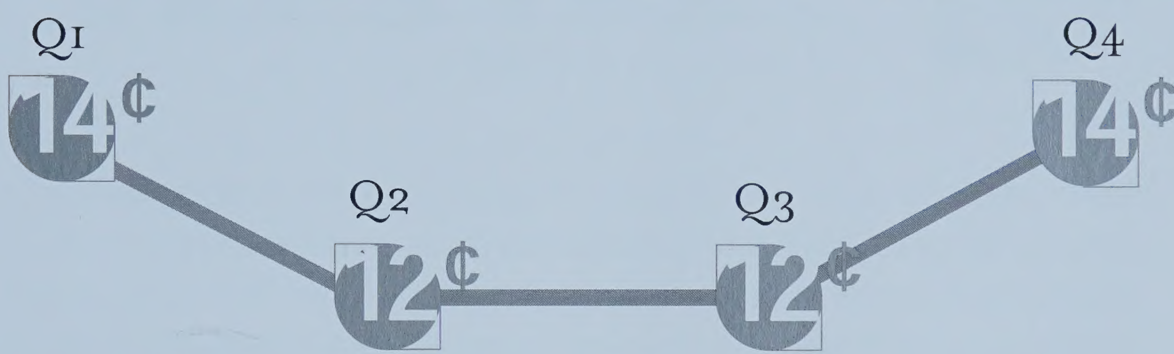
2003 saw significant changes in virtually all key financial and operating metrics.

In 2002, management focused on managing the construction of the Joffre Extraction Plant, a $45 million gross project. In 2003, Taylor commissioned Joffre, acquired the RET Complex, and re-set Taylor's capital structure for future growth with a $45 million equity offering and the refinancing of term debt.

Years ended December 31, (thousands of dollars except unit values and volumes)	2003	2002
FINANCIAL		
Gross revenue	$ 116,149	$ 85,087
Distributable cash flow	$ 7,211	$ 4,375
Fully diluted per unit	$ 0.52	$ 0.45
Net income	$ 3,574	$ 4,100
Diluted per unit	$ 0.31	$ 0.42
Capital expenditures	$ 33,020	$ 17,774
Unit price		
High	$ 6.35	$ 4.94
Low	$ 4.35	$ 4.24
Close	$ 6.10	$ 4.54
Units traded	6,308,134	3,865,615
Value of units traded	$ 33,863	$ 17,781
Outstanding units at year-end	18,005,763	9,722,713
OPERATIONS		
Gas volumes processed (mmscf/day)	303	297
Daily average production (bbls/day NGL)	13,794	13,137

2003 distributions per unit were stable.

In spite of volatile commodity pricing patterns that Taylor endured through the middle of 2003, distributions to unitholders were stable because of the structure of the commercial arrangements that underpin the business.



Q1

9.7 million units outstanding

- Joffre Extraction Plant began commercial operations with sales of ethane and C_3^+.

Q2

9.7 million units outstanding

- High natural gas price and low NGL prices.
- Production curtailed at both Younger and Joffre.

Q3

18.0 million units outstanding

- NGL margins recover as natural gas prices fall.
- Younger and Joffre operated to maximize production.
- Closed acquisition of the RET Complex.
- Issued 8.25 million units to raise $45 million.

Q4

18.0 million units outstanding

- First full quarter of RET Complex contributions.
- Began restructuring debt, completed early January 2004.

Letter To Unitholders

Two-thousand-three was a pivotal year for Taylor NGL Limited Partnership in which the asset base was successfully diversified, both geographically and by business type.

Taylor added two facilities during the year – the Joffre Extraction Plant in central Alberta and the RET Complex, a group of three natural gas processing plants located in southern Alberta. The successful addition of these assets is testament to the effectiveness of a business strategy that is focused on growing and diversifying the Partnership.

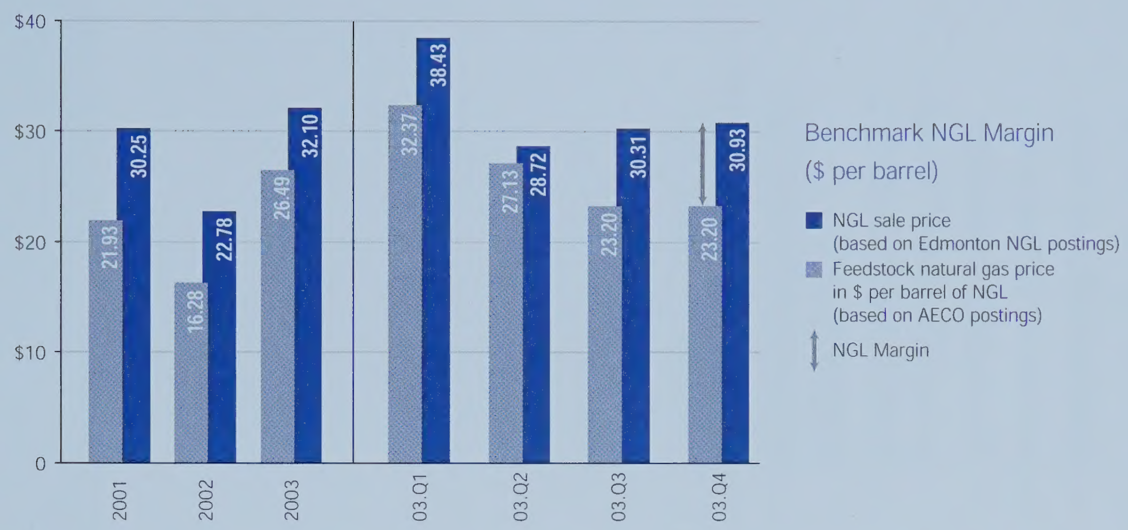
Taylor's market capitalization increased to $110 million through 2003, compared to $44 million at year-end 2002, in part as a result of a very successful $45 million equity offering completed in the third quarter. The proceeds of this offering were used to repay the bridge facility that financed the purchase of the RET Complex and to retire a portion of the bank debt that was used to build the Joffre Extraction Plant. Taylor enters 2004 on a sound financial footing and with three core assets providing a strong platform for further growth.

During the year Taylor distributed $0.52 per unit to investors on a 100 percent tax-deferred basis. In addition, Taylor's unit price increased to $6.10 at year-end, up from $4.54 at the beginning of 2003. The combined distribution and increase in unit price resulted in a unitholders' total return in calendar 2003 of more than 45 percent.

Taylor's Assets

The Partnership owns and operates facilities that are in the midstream sector of the western Canadian natural gas industry. Two of these facilities, the Joffre and Younger extraction plants, produce ethane, propane, butane and condensate – products collectively known as natural gas liquids, or NGLs. The Younger Plant, located in northeast British Columbia, was Taylor's first asset. The Joffre Plant was built by the Partnership in 2002 and began commercial operations in the first quarter of 2003.

In September 2003, the Partnership acquired the RET Complex, three interconnected natural gas processing plants, and their associated pipeline systems. The RET Complex provides gathering, compression and processing to natural gas producers on a fee-for-service basis. The RET Complex is in the heart of a highly active natural gas exploration and development region and, due to its strong regional franchise, provides Taylor with stable business income.



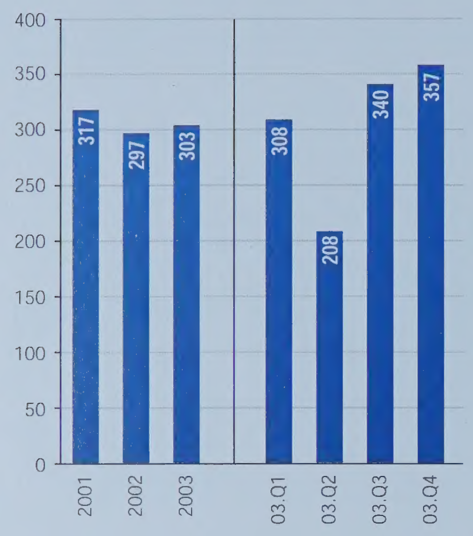
The Partnership's assets have a very long economic life. The NGL extraction business is founded on regional natural gas supply and demand. The Younger Plant is supplied from the robust northeastern British Columbia natural gas producing area; the Joffre Plant depends on the fuel gas demands of central Alberta's ethane-based petrochemical industry. The RET Complex will have strong cash flow for many years based on regional natural gas reserves and production profiles.

The Partnership holds a controlling interest in, and operates all of its assets, allowing management to fully optimize the business at each of the facilities. With this hands-on approach, management is also in a position to capture upside opportunities that result from Taylor's significant presence around each of its three core locations.

A Sound Business Model

The Partnership's goal is to generate a stable, base level of distributions to unitholders, while providing upside when commodity prices are favourable or through expanding the commercial base. Management has achieved this by carefully considering the level and type of risks to which the Partnership is exposed. Essentially, Taylor takes on risks that are manageable and sheds risks that are inappropriate for our unitholders.

For example, Taylor has commercial arrangements in place at the Younger and Joffre extraction plants that manage the Partnership's exposure to price movements in both natural gas and natural gas liquids. An asymmetrical risk profile has been achieved through the structure of Taylor's long-term commercial arrangements. This profile gives the Partnership a minimum price for the produced natural gas liquids while maintaining economic participation in price upswings through the profit-share arrangements at Younger and the merchant sale of Joffre production.



Natural Gas
Processed by Taylor
(mmscf per day)

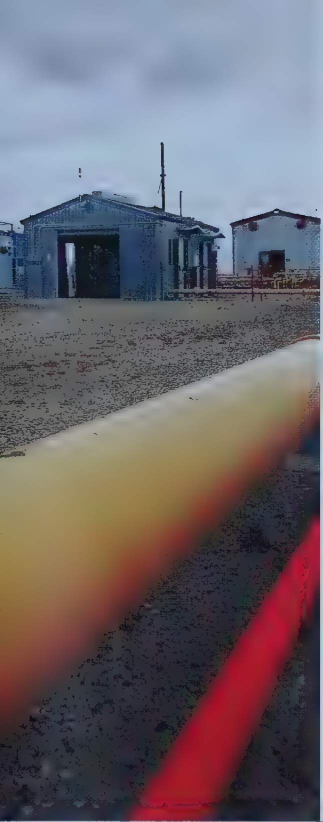
The Partnership has also managed risk through regional, commercial and operational diversification. The Younger and Joffre extraction plants operate in two distinct regions of western Canada and sell natural gas liquids into different markets. Over the long-term, the Younger and Joffre plants are counter-cyclical to the RET Complex. The volume of natural gas delivered to the RET Complex for processing tends to increase with natural gas prices. (Strong prices drive exploration and production activity). The natural gas liquids extraction business, which purchases natural gas as feedstock, is most profitable when natural gas prices are low. (The margin between revenue and expenses increases as natural gas prices fall).

Outlook

Strong natural gas prices over the past year, which are expected to continue, are driving active exploration and development of natural gas reserves by producing companies. As a result, the RET Complex is the beneficiary of increasing natural gas production in its broad capture area in southern Alberta.

On the extraction side, prices received for natural gas liquids are linked to crude oil prices. Since oil prices are strong as we enter 2004, Taylor's extraction business is enjoying reasonable margins in the production and sale of natural gas liquids despite the high natural gas prices.

Since the Younger Plant is being operated to maximize the amount of natural gas liquids extracted from the natural gas that is being processed, future production growth depends on management's ability to increase the volume of natural gas brought through the plant. Taylor will continue to compete for feedstock natural gas by offering customers creative commercial arrangements and pricing options.



Taylor NGL Sales (barrels per day)

Similarly, natural gas liquids production at the Joffre Plant will depend on the volume of natural gas that is processed at the plant. The natural gas volumes available to Joffre are determined by the downstream demand at the adjacent NOVA Chemicals Corporation's petrochemical facility and the related plants that comprise the Joffre industrial complex.

Entering 2004, management is again evaluating projects and acquisitions in the western Canadian oil and natural gas infrastructure sector that will further diversify and increase the Partnership's operating income. We can achieve growth by further developing the Partnership's assets as well as the acquisition or development of new core assets.

Acknowledgements

The Board of Directors wishes to thank Taylor's staff in Calgary, at the Younger and Joffre plants and at the RET Complex for their contributions in 2003.

As we continue to move beyond our British Columbia roots, the directors have contributed wisdom and guidance and we thank them for their support during the year. We look forward to working with the directors in 2004, as we grow Taylor's business. We also thank our investors for their loyalty and look forward to continuing to provide value.

On behalf of the Board of Directors,

Robert J. Pritchard
President and C.E.O.
Taylor Gas Liquids Ltd.
March 17, 2004

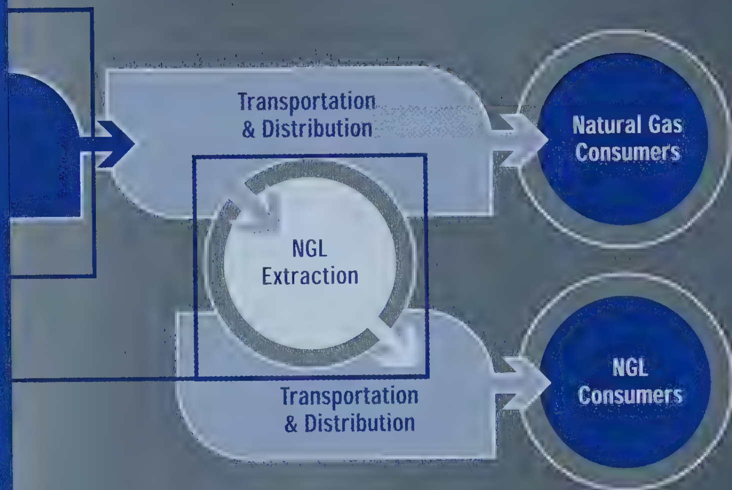
Operations Review

Where Taylor fits in the natural gas industry

Taylor occupies a position in the natural gas value chain through its ownership in three large-scale facilities that are integral to the movement of natural gas from wellhead to end-users.

and other

essing plants



plant. The gas is

condensate to a

form a residue natural gas stream that is returned to the

butane and condensate,

petrochemical industry. Uses for

Taylor owns and operates the Younger and Joffre extraction plants and the RET Complex.

- Located at Taylor, British Columbia.
- Taylor is operator of the plant and controls 425 mmscf per day of gas processing capacity.
- Provides natural gas liquids extraction and terminalling services on both a proprietary and a fee-for-service basis.
- Produces ethane, propane, butane and condensate. Taylor's net 2003 production was four million barrels.

- Located at Joffre, Alberta.
- Taylor is operator of the plant and has 125 mmscf per day of net gas processing capacity.
- Constructed by Taylor in 2002, commercial operations began in the first quarter of 2003.
- Provides natural gas liquids extraction and terminalling services on a proprietary basis.
- Produces ethane and C_3^+. Taylor's net 2003 production was one million barrels.

Edmonton

Calgary

- Located in the Lethbridge area of Alberta.
- Taylor is operator of the plants and has 104 mmscf per day of net gas processing capacity.
- Purchased by Taylor effective September 1, 2003.
- Provides natural gas gathering and processing services on a fee-for-service basis.
- Taylor does not take title to any of the products produced at the plants.

Vancouver

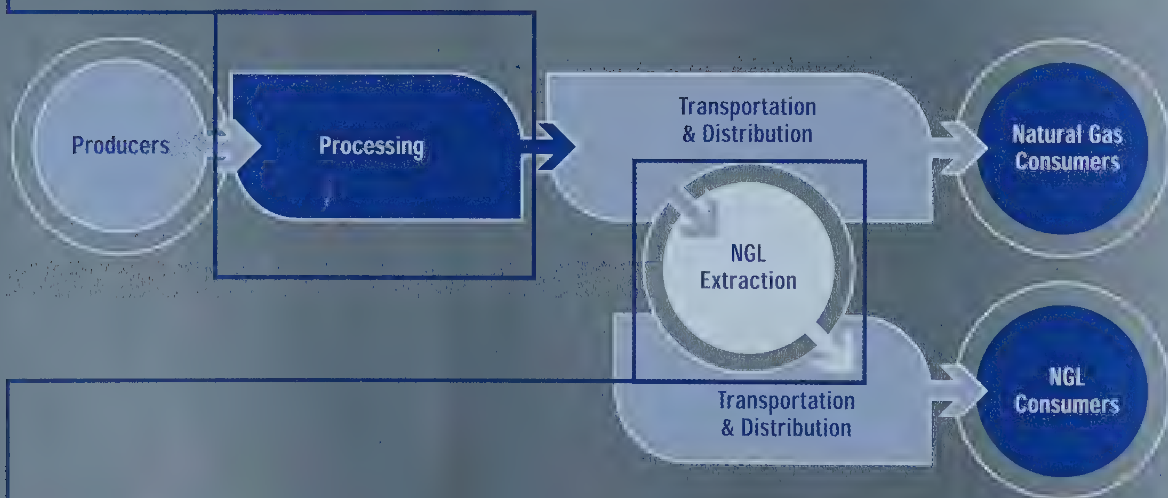
What is shrinkage?

In the eyes of a shipper that is moving natural gas on the transmission system, the extraction of natural gas liquids looks like a natural gas sale. The extracted components are often referred to as shrinkage since their removal results in a reduction, or shrinkage, of the natural gas stream. The extraction plant owner must compensate the gas shipper for this shrinkage which is essentially the feedstock cost for the natural gas liquids production. Therefore, the economics of natural gas liquids extraction are directly related to the difference between the value of ethane, propane, butane and condensate as separate, marketable commodities and their shrinkage value as constituents of the natural gas stream.

Operations Review

Natural Gas Processing

[illegible] through a pipeline network, or gathering syst[illegible] [illegible]



Natural Gas Liquids Extraction

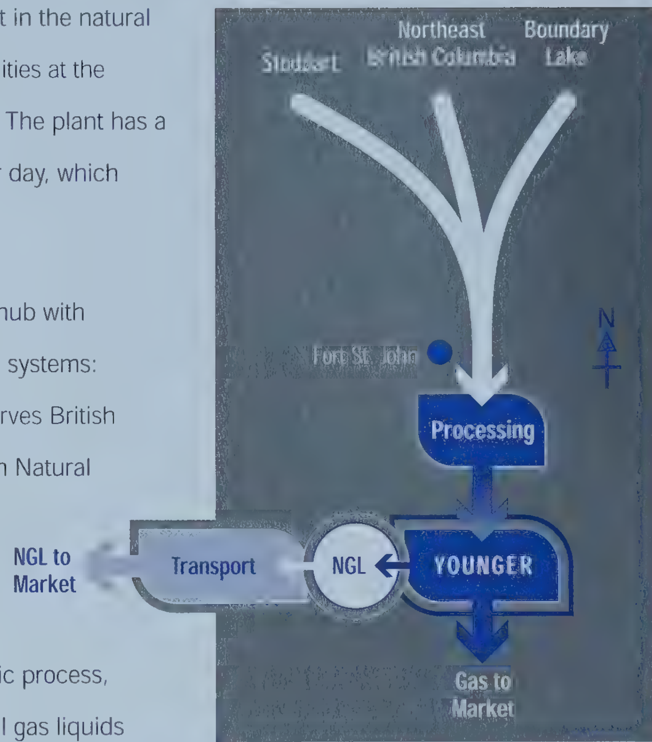
[illegible] gas is mainly methane, but also contains ethane, propane, butane and condensate. [illegible]

[illegible]

Younger Extraction Plant

Taylor owns interests ranging from 57-100 percent in the natural gas liquids extraction, treating and terminalling facilities at the Younger Plant, located in Taylor, British Columbia. The plant has a natural gas processing capacity of 750 mmscf per day, which includes Taylor's share of 425 mmscf per day.

Younger is strategically located at a major energy hub with interconnections to three natural gas transmission systems: the Duke Energy Gas Transmission system that serves British Columbia and the Pacific Northwest; the Canadian Natural Resources' Stoddart system that brings natural gas to Younger from northeastern British Columbia; and the Alliance system that moves natural gas to the Chicago area. With its state-of-the-art cryogenic process, Younger removes as much as 50 barrels of natural gas liquids from each million standard cubic feet of natural gas processed through the plant.

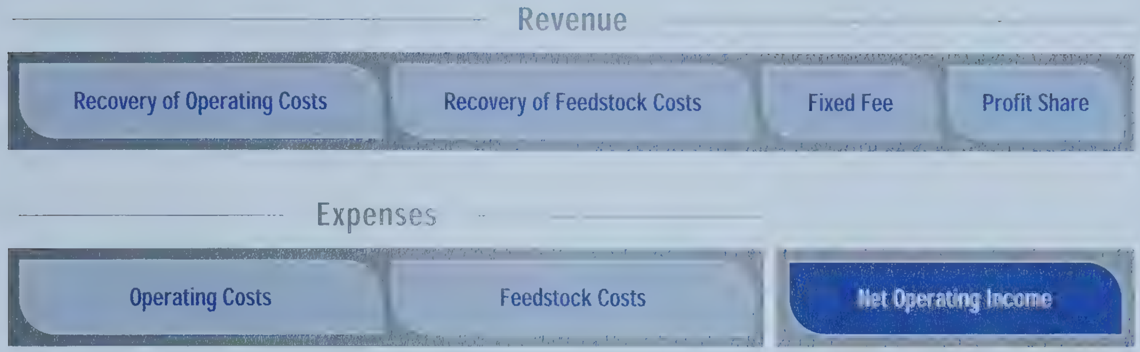


Business Model

Taylor's business model at Younger involves purchasing natural gas as feedstock, then extracting and selling ethane, propane, butane and condensate. Taylor has structured its natural gas liquids sales arrangements in a way that manages the Partnership's exposure to fluctuating commodity prices.

The natural gas liquids produced by Taylor at the Younger Plant are sold to EnCana Corporation under a long-term contract. The sales price includes the recovery of actual operating and feedstock costs, as well as a fixed fee and a profit share. The profit share component of Taylor's sales price is a 50-percent participation in the revenue that EnCana Corporation realizes from the final sale of the natural gas liquids that it purchases from Younger, minus all costs. When the costs exceed the price received by EnCana Corporation at final sale the deficiency is held in a deferral account and carried forward to be retired by future profits.

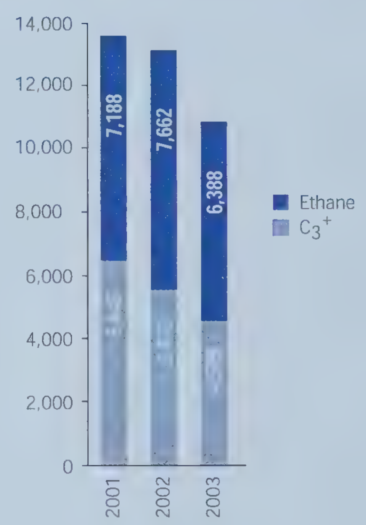
Younger Extraction Plant · Net Operating Income



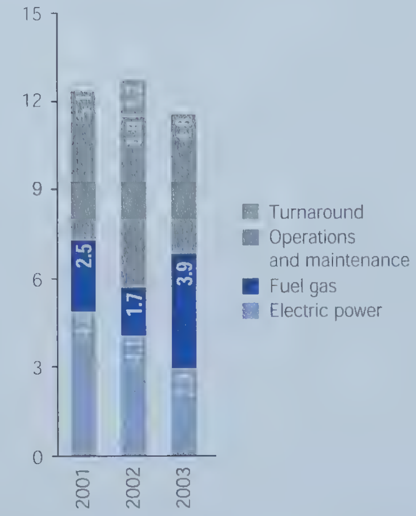
Production and Operations

During 2003, production of natural gas liquids at the Younger Plant averaged 10,897 barrels per day, significantly lower than the 13,137 barrels per day in 2002. The decrease was due to the deliberate decision to curtail production in the second quarter in response to market conditions. During May and June production was reduced by two-thirds, due to very low margins in natural gas liquids extraction – margin being the difference between the value of the produced natural gas liquids and the cost of natural gas feedstock. These market conditions had minimal financial impact on unitholders due to the structure of the natural gas liquids sales contract and the ability to physically curtail production at the plant.

As a result of the production curtailment, Taylor processed an average of 229 mmscf per day of natural gas over the year, significantly less than the 2002 average of 297 mmscf per day.



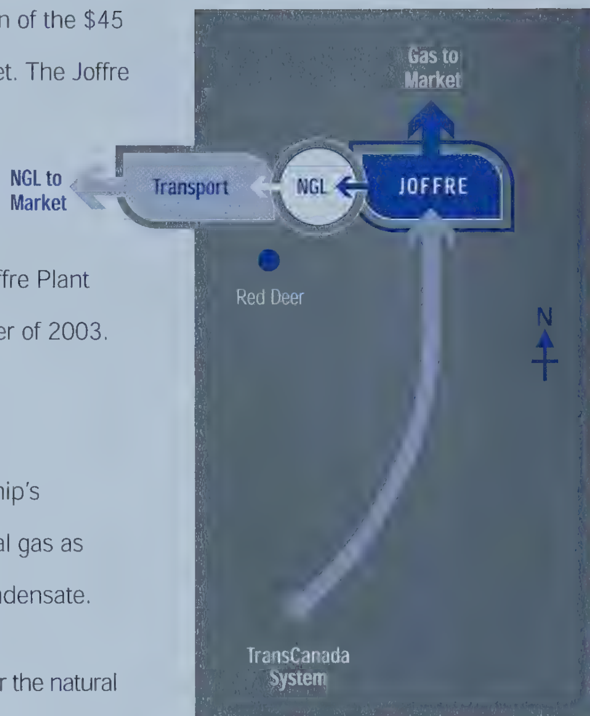
Younger NGL Production (barrels per day)



Younger Operating Costs ($ millions)

Joffre Extraction Plant

In late 2002, the Partnership completed construction of the $45 million Joffre Extraction Plant, on time and on budget. The Joffre Plant extracts the natural gas liquids from the fuel gas that is supplied to NOVA Chemicals Corporation's nearby world-scale petrochemical facility. Following commissioning and testing, the Joffre Plant commenced commercial operation in the first quarter of 2003.

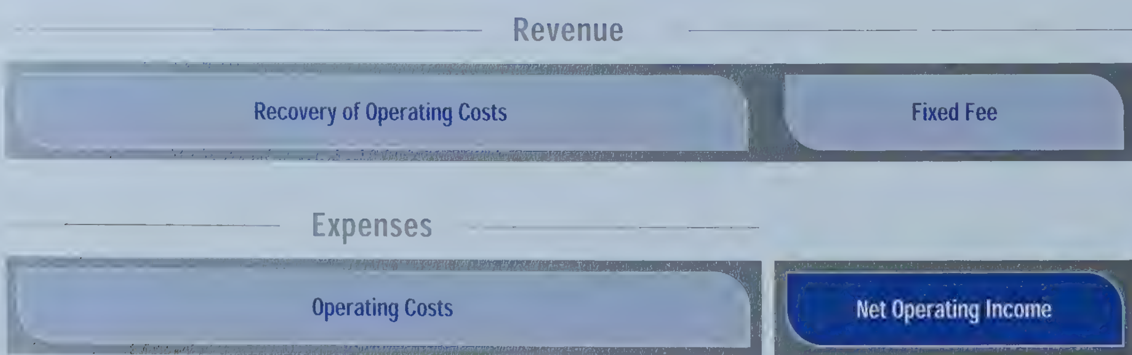


Business Model

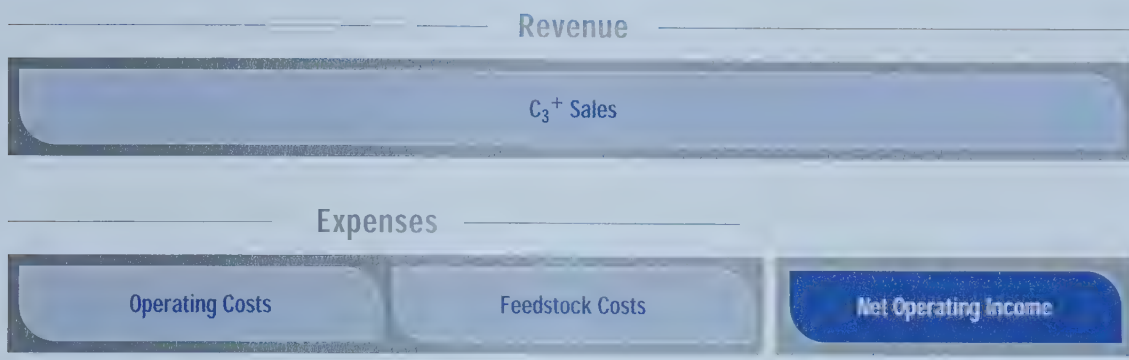
The Joffre business model is similar to the Partnership's arrangements at the Younger Plant: purchase natural gas as feedstock and sell ethane, propane, butane and condensate.

Similar to the Younger Plant, the sales arrangements for the natural gas liquids produced at the Joffre Plant have been structured to manage commodity price exposure. NOVA Chemicals Corporation purchases the ethane under a long-term contract that provides for the recovery of operating costs and the payment of a fixed fee. The remaining portion of the natural gas liquids – the propane, butane and condensate – is sold into the Alberta market at prevailing prices. Unique among straddle plants, the Joffre Plant has been configured so that management can very quickly respond to market conditions by selectively rejecting some or all of the plant's natural gas liquids production. If margins are poor, the plant will simply not recover natural gas liquids and therefore not incur feedstock costs.

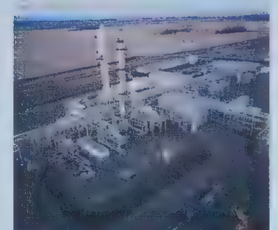
Joffre Extraction Plant · Ethane Net Operating Income



Joffre Extraction Plant · C_3^+ Net Operating Income



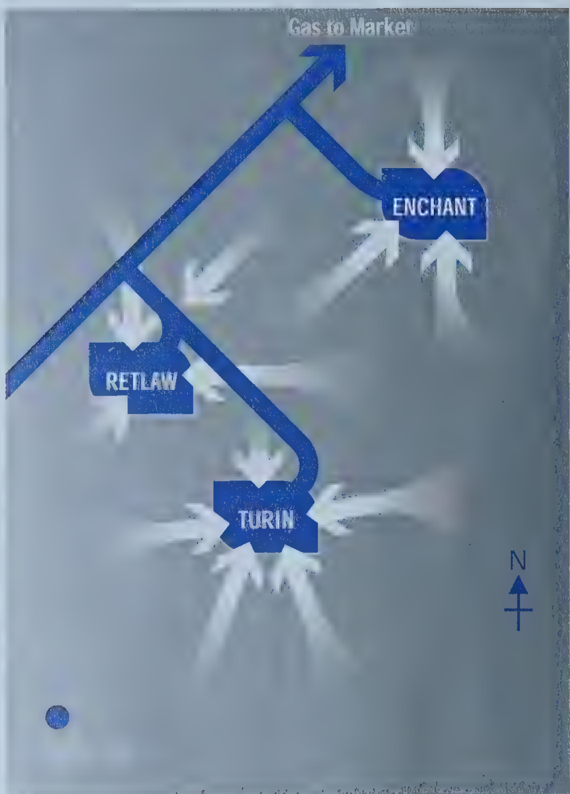
Production and Operations



The Joffre Plant has been operating since the first quarter of 2003, with first year operational performance exceeding expectations. The incorporation of the latest process technologies has resulted in a plant that is low cost and very reliable. The plant had an on-line time in excess of 99 percent through 2003.

Natural gas liquids production net to the Partnership averaged 2,897 barrels per day in 2003. Like Younger, Joffre production was managed very closely through the second quarter due to the very tight margins in natural gas liquids production. As a result, propane, butane and condensate were not produced at the Joffre Plant from mid-April to mid-June. Illustrative of the operational flexibility of the plant, ethane production was maintained throughout the period when the other components of the natural gas liquids were being re-injected. To maximize ethane production, the volume of natural gas processed was maintained, averaging 55 mmscf per day net to the Partnership for the year.

RET Complex



The Partnership added a third core asset in September 2003 with the acquisition of the RET Complex, a group of three interconnected natural gas processing plants – Retlaw, Enchant and Turin – and 500 kilometres of associated pipelines that gather natural gas from an area in excess of 2,500 square kilometres.

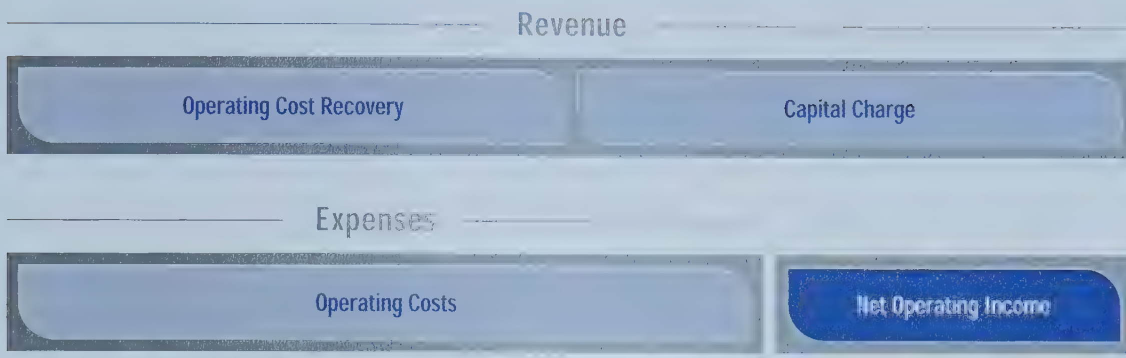
All three plants are capable of handling both sweet and sour natural gas. Following processing, each plant delivers sales quality natural gas to the TransCanada system on behalf of producers that have contracted for services from Taylor.

The Turin Plant, built in 1974 with a major upgrade in 1981, has a capacity of 44 mmscf per day. The Partnership owns 72.3 percent of Turin and operates the facility. The Retlaw Plant, built in 1964 with a major upgrade in 1994, has a capacity of 15 mmscf per day. The Partnership owns 83.5 percent of Retlaw and operates the plant. The Enchant Plant was built in the 1960s and underwent major upgrades in 1995 and 1997. Owned and operated 100 percent by the Partnership, Enchant can process 22 mmscf per day of sour natural gas and 60 mmscf per day of sweet natural gas.

Business Model

The RET Complex generates revenue by charging fees for natural gas well operations, natural gas gathering and natural gas processing. Producers that move natural gas through the RET Complex negotiate fee-for-service contracts with the Partnership that outline the services to be provided by Taylor, the terms and conditions relating to the provision of such services and the fee to be paid by the producer. Factors that influence the fee charged include term of contract, volume commitment by the producer and degree of processing required to meet sales gas specifications. Processing fees tend to be higher for sour natural gas than for sweet natural gas due to more extensive processing requirements.

RET Complex · Net Operating Income



Fee-for-service contracts typically include both an operating cost recovery component and a capital charge component derived from the value of the equipment that is used to provide the services to the producer. The operating cost recovery component is linked to the actual operating costs of the facilities that are used to handle and process the producers' gas. With this fee structure, the Partnership's revenue does not have any direct commodity price exposure.

Operations

The RET Complex has historically experienced stable natural gas volumes being delivered for processing. This stability reflects a diverse customer base and an extensive gathering system that results in a strong franchise area with both physical and regulatory barriers to entry. The natural gas producer community is active in the region due to low exploration and development costs and year-round access. The RET Complex capture area is rich in prospective geological zones with production being derived from more than 15 distinct horizons.

Since taking ownership of the RET Complex, Taylor has worked hard to attract more natural gas volumes for processing. In December, the RET Complex processed more than 58 mmscf per day net to the Partnership, an increase of 10 percent from September, when the RET Complex was acquired.

Management's Discussion and Analysis

The following should be read in conjunction with the audited financial statements and notes of Taylor NGL Limited Partnership (the Partnership). The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles.

Certain information included herein is forward-looking and based upon assumptions and anticipated results that are subject to uncertainties. Should one or more of these uncertainties materialize or should the underlying assumptions prove incorrect, actual results may vary significantly from those expected.

Tabular amounts are expressed in thousands of dollars except per unit amounts. All figures are in Canadian dollars unless otherwise stated.

Overview of the Year 2003

In 2003, Taylor successfully grew and diversified its asset and revenue base with the addition of two significant facilities – the Joffre Extraction Plant in central Alberta and the RET Complex comprising three interconnected natural gas processing plants and their associated gathering systems located in southeastern Alberta.

Construction of the Joffre Extraction Plant was completed on time and on budget in the fourth quarter of 2002 for a gross cost of $45 million, with commercial operations beginning in the first quarter of 2003. The Partnership is the operator and has a 50-percent interest in this 250 mmscf per day facility. At year-end 2003, the Joffre Extraction Plant accounted for approximately 25 percent of the Partnership's operating income.

In September 2003, the Partnership acquired the RET Complex for a purchase price of $30.5 million. To finance the acquisition, the Partnership arranged a non-revolving bridge facility with AltaGas Services Inc. in the amount of $30.5 million. The Partnership is the operator of each of the plants and has a volume weighted average ownership of 87.6 percent. At year end 2003, the RET Complex accounted for approximately 40 percent of the Partnership's operating income.

Younger and Joffre return-on-capital-derived fixed payments, and the RET Complex fee-for-service accounted for 93 percent of the Partnership's operating income.

In addition to the fixed payments and fee-for-service sourced revenue, Taylor participates in commodity price upside, at Younger through the profit share, or marketing pool, and at Joffre through the sale of natural gas liquids, other than ethane. The operating income from this commodity price exposure is a function of the natural gas liquids margin which is the difference between the natural gas liquids sales price and the natural

gas feedstock price. In 2003, the natural gas liquids margin was such that natural gas liquids sales at Joffre contributed to operating income. However, the natural gas liquids margin was not sufficient to result in an operating income contribution from the Younger marketing pool. Over 2003, the deficiency balance in the pool increased from $1.6 milllion at the beginning of the year to $3.0 million at year-end.

In October 2003, the Partnership closed a follow-on offering of 8.3 million limited Partnership units for gross proceeds of $45.0 million which resulted in net proceeds of $42.4 million. These funds were used to fully repay the AltaGas bridge loan facility and to retire $8.4 million of existing Joffre construction-related bank debt.

In January 2004, to provide Taylor with increased debt capacity, the Partnership's term debt facilities, which totalled $20 million at December 31, 2003, were refinanced into a $26 million revolving credit facility and a $2 million reducing term facility.

Outlook for 2004

The Partnership's long-term goal is to increase distributions to Unitholders by executing a business plan that diversifies and grows the Partnership's sources of revenue.

The commercial arrangements around Taylor's business are structured to provide Unitholders with a significant component of operating income that is stable and predictable. Under long-term agreements with EnCana Corporation and with NOVA Chemicals, Taylor receives, at a minimum, a return-on-capital-derived fixed payment for the natural gas liquids produced at Younger and for the ethane produced at Joffre. Also, the stable fee-for-service revenue provided by the RET Complex is low risk due to the portfolio of contracts with a diverse and active customer base.

If the natural gas liquids margin remains at 2003 levels, the sale of natural gas liquids at Joffre will result in a positive contribution to 2004 operating income. However, at this level of natural gas liquids margin, the Younger Plant marketing pool, with its beginning deficit balance of $3 million, will not contribute to 2004 operating income.

In 2004, the RET Complex will contribute to operating income for a full year compared to four months in 2003. In addition, if producers continue to maintain recent levels of drilling activity in the RET Complex capture area, natural gas volumes processed by the RET Complex will continue to exceed the levels being processed when Taylor acquired this asset.

Critical Accounting Policies and Estimates

In the preparation of the Partnership's consolidated financial statements, management has made estimates that affect the recorded amounts of certain assets, liabilities, revenues and expenses. All estimates are

adjusted for events that are known to have a significant effect on the current month's operations, such as scheduled or unscheduled plant shut-downs. Given the amount of historical data available for both the Younger and Joffre plants, management has been able to make these estimates with a high degree of accuracy for each of these facilities. After four months of operations at the RET Complex, management has been able to make these estimates with increasing accuracy and continues to be conservative in recording results. There are no known trends, events or uncertainties to indicate that actual results will vary significantly from the estimates used at year-end 2003, nor would any expected variance have a material effect on the financial condition of the Partnership. Based on the Partnership's approach to managing business risks, the most significant accounting policies and estimates are those described below.

Younger Revenue and Expenses

Given the nature of the Partnership's commercial arrangements at the Younger Plant, estimates are immaterial in the preparation of the Partnership's financial statements.

Joffre Natural Gas Liquids Sales and RET Complex Fee Income

Actual production, natural gas liquids sales and fees earned are unknown at the end of each month. Accordingly, the financial statements contain an estimate of one month's revenue based upon expected volumes and expected natural gas liquids prices supported by comparison to historical trends. The combined revenue estimate for natural gas liquids sales and fee income for the month of December 2003 was $1.5 million, which was included in revenue and accounts receivable.

Joffre Natural Gas Liquids Shrinkage Gas Expenses

The cost and quantity of natural gas purchased as feedstock, or shrinkage gas, for the extraction of NGLs, other than ethane, are unknown at the end of each month. Accordingly, the financial statements contain an estimate of one month's shrinkage gas expense based upon expected volume and expected natural gas prices supported by comparison to historical trends. The estimate for shrinkage gas expense for the month of December 2003 was $0.6 million, which was included in expenses and accounts payable.

Joffre and RET Complex Operating Costs

The period in which invoices are rendered for the supply of goods and services necessary for the operation of the facilities is generally later than the period in which the goods or services were provided. Accordingly, the financial statements contain an estimate of one month's operating costs based upon a review of actual activity at each facility, including adjustments for events that are known to have a significant effect on the month's operations. These include maintenance activity or changes in production supported by comparison

to historical trends. At December 31, 2003 operating expenses and accounts payable include an estimate for December 2003 operating expenses of $0.5 million.

Asset Retirement Obligations

Effective January 1, 2004, the Partnership is required to adopt new accounting standards with respect to asset retirement obligations. The fair value of estimated asset retirement obligations will be recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The liability amount will be increased in each reporting period due to the passage of time, and the amount of accretion will be expensed in the period. Management believes that the impact of adopting the new accounting standard will be immaterial.

Operating Results Summary

Consolidated Overview – Quarterly Information
(in thousands of Canadian dollars except for volume and unit amounts)

2003

(Quarter Ended)	March 31	June 30	Sept. 30	Dec. 31	Total
NGL sales (barrels per day)	14,605	9,363	15,832	15,416	13,794
Natural gas processed (mmscf/d)	308	208	340	357	303
Total revenue	34,767	18,372	30,901	32,110	116,149
Total expenses	32,798	16,893	29,790	29,994	109,475
Distributions to unitholders	1,362	1,169	2,159	2,521	7,211
Distributions per Partnership unit	0.14	0.12	0.12	0.14	0.52

2002

(Quarter Ended)	March 31	June 30	Sept. 30	Dec. 31	Total
NGL sales (barrels per day)	11,977	14,702	11,914	13,838	13,137
Natural gas processed (mmscf/d)	303	327	262	282	297
Total revenue	15,835	21,126	15,921	32,206	85,087
Total expenses	14,754	19,711	14,958	30,696	80,119
Distributions to unitholders	972	972	1,069	1,362	4,375
Distributions per Partnership unit	0.10	0.10	0.11	0.14	0.45

Following the acquisition of the RET Complex on September 1, 2003, Taylor's total natural gas volumes processed increased by 27 percent to 357 mmscf per day in the fourth quarter of 2003 compared to 282 mmscf per day in the 2002 comparable quarter. Sales of natural gas liquids increased to 15,416 barrels per day in the fourth quarter of 2003 compared to 13,838 barrels per day in the 2002 comparable quarter.

For the year ended December 31, 2003, Taylor processed 303 mmscf per day of natural gas versus 297 mmscf per day in 2002. Sales of natural gas liquids totalled 13,794 barrels per day for 2003, an increase of 5 percent from the 13,137 barrels per day in 2002. Operations at both the Younger and Joffre extraction plants were significantly impacted during the second quarter by the dramatic reduction in margins. Because of the physical configuration of both plants, Taylor was able to bypass natural gas and/or reinject natural gas liquids when margins were unfavourable.

Cash Distributions

Cash distributions for the quarters and years ended December 31, 2003 and 2002 are calculated by adding back non-cash items and working capital amounts to net income:

(in thousands of dollars except per unit amounts)	Three Months Ended Dec 31		Year Ended Dec 31	
	2003	2002	2003	2002
Distributions to unitholders				
Net income	$ 1,310	$ 3,141	$ 3,574	$ 4,100
Depreciation	1,267	673	3,980	2,663
Unrealized foreign exchange loss (gain)	1,234	(40)	83	(68)
Recognition of deferred performance fee	–	–	750	–
Working capital withheld	(1,290)	(2,412)	(1,176)	(2,320)
	$ 2,521	$ 1,362	$ 7,211	$ 4,375
Distributions per Partnership unit	$ 0.14	$ 0.14	$ 0.52	$ 0.45

The Partnership pays cash distributions on a quarterly basis to unitholders of record on February 5, May 5, August 5 and November 5. Distributions are payable on the fifteenth day of that same month. Currently, cash distributions are 100 percent tax-deferred and characterized as a return of capital. For most unitholders, the return of capital will reduce the cost base of each unit for the purposes of calculating any capital gains when the units are ultimately sold.

For the year ended December 31, 2003 the Partnership distributed $7.2 million or $0.52 per unit to unitholders, compared to $4.4 million, or $0.45 per unit in 2002.

Fiscal Quarter	Distribution Paid	Distribution per Unit
Q1 2003	May 15, 2003	$ 0.14
Q2 2003	August 15, 2003	$ 0.12
Q3 2003	November 15, 2003	$ 0.12
Q4 2003	February 15, 2004	$ 0.14

Natural Gas Liquids Sales

Natural gas liquids sales revenue is derived from the sale of production from the Younger and Joffre plants. For the year ended December 31, 2003, natural gas liquids sales revenue was $106 million compared to $78 million in 2002.

Natural gas liquids sales revenue at the Younger Plant, as defined under the Natural Gas Liquids Purchase Agreement with EnCana Corporation, includes recovery of feedstock and operating costs, a return-on-capital-derived fixed fee, and a 50 percent profit share based on both an operating cost hurdle (Operating Pool) and natural gas liquids margin (Marketing Pool). Natural gas liquids sales revenue at the Joffre Plant includes a return-on-capital-derived fixed fee and recovery of operating costs, attributable to ethane production as defined under the Ethane Supply Agreement with NOVA Chemicals Corporation, plus C_3^+ sales revenue.

The largest component of natural gas liquids sales revenue is the recovery of Younger Plant natural gas feedstock costs or shrinkage gas. The increase in natural gas liquids sales revenue for the year was primarily due to higher natural gas prices during 2003 compared to 2002. The AECO daily natural gas price, which is an indication of the Partnership's actual natural gas purchase price, averaged $6.35 per gigajoule (GJ) during 2003 versus an average of $3.97 per GJ during 2002.

Fee Income

Fee income consists of revenue received from processing natural gas at the RET Complex, fees from third-party use of Younger Plant facilities and overhead recoveries in respect of operations at all facilities. Fee income for the year ended December 31, 2003 was $10 million compared to $7 million in 2002. The increase in fee income in 2003 was due to the inclusion of processing fee revenues attributable to the RET Complex.

Shrinkage Gas

The cost of natural gas feedstock, commonly known as shrinkage gas, was $88 million for the year ended December 31, 2003 compared to $65 million in 2002. The increase in 2003 was primarily due to higher natural gas prices during the year compared to 2002 and the purchase of shrinkage gas for C_3^+ production at the Joffre Plant. These increased costs were offset by the increase in natural gas liquids sales revenue, as previously discussed.

Operating Costs

Operating costs for the year ended December 31, 2003 were $16 million compared to $12 million in 2002. The increase was due to the commencement of commercial operations at the Joffre Plant in the first quarter of 2003, the inclusion of four months of operations at the RET Complex, and higher fuel gas costs at the Younger and Joffre plants as a result of increased natural gas prices.

Administration Costs

The 2003 administration costs, net of overhead recoveries, were $0.8 million compared to a nominal amount in 2002. The low amount in 2002 was due to high overhead recoveries attributable to the construction of the Joffre Plant. During 2003, these same recoveries were not available as construction of the Joffre Plant was completed in December 2002. In addition, administration costs increased over 2002 as a result of the RET Complex acquisition and business development activities.

Depreciation

Depreciation expense in 2003 was $4 million compared to $3 million in 2002. The increase was due to depreciation on the Joffre Plant, which commenced operations in January 2003, and to depreciation on the RET Complex, which was acquired in September 2003.

Interest Expense

Interest costs were $1.6 million for the twelve months ended December 31, 2003 compared to $0.3 million in 2002. The increase resulted from interest costs on the bank debt related to the construction of the Joffre Plant being capitalized in 2002. In addition, the interest cost associated with the bridge loan facility used to finance the acquisition of the RET Complex was expensed during September 2003. The average annual interest rate on the Partnership's bank debt and bridge loan for 2003 was 4.9 percent compared to 4.6 percent during 2002.

Foreign Exchange

The Partnership retired its U.S.-dollar denominated debt from proceeds received from the public offering of limited partnership units in October 2003. The repayment of the U.S. dollar denominated debt resulted in a foreign exchange gain of $1.7 million, offset by a foreign exchange loss of $0.5 million on U.S. denominated cash that was held by the Partnership.

Management Fees, Overhead Recovery Fees and Distributions to Limited Partners

Management fees payable to the Manager in 2003 were $0.3 million, similar to 2002.

For the twelve months ended December 31, 2003, overhead recovery fees were $1.5 million compared to $1.7 million in 2002. The decrease was due to higher overhead recovery fees associated with the construction of the Joffre Plant during 2002.

Distributions to limited partners in 2003 were $1.3 million compared to $1.5 million in 2002. These distributions relate to the option held by the limited partners, other than the Partnership, of the Taylor Gas Liquids Limited Partnership (TGLLP) to contribute 26.75 percent of capital expenditures of TGLLP and receive distributions equal to the associated return-on-capital earned by TGLLP.

Insurance

In December 2002, the Partnership recorded a one-time contribution to income of $2.6 million for insurance recovery. This was the result of settling the property reconstruction and business interruption insurance claims arising from the 1999 incident at the Younger Plant.

Income and Capital Taxes

Income and capital taxes were nil in 2003 and 2002. As a limited partnership, Taylor does not provide for income and capital taxes. Due to its partnership status, Taylor's taxable income is allocated to unitholders at each year-end.

Net Income

Net income was $3.6 million for the year ended December 31, 2003 compared to $4.1 million in 2002, as a result of the foreign exchange gain realized in 2003 and insurance recoveries in 2002. Excluding these one-time events, net income would have been $2.4 million for the year ended December 31, 2003 compared to $1.5 million for 2002. The increase of $0.9 million in net income is primarily the result of operations at the Joffre Plant for approximately twelve months and from the RET Complex for four months.

Marketing Pool

The Younger Plant marketing pool did not contribute to distributions in 2003 or in 2002. The marketing pool opened 2003 with a deficit balance of $1.6 million, which increased to an estimated balance of $3.0 million at December 31, 2003 due to poor natural gas liquids margins during the second quarter of 2003.

Capital Expenditures

Including the RET Complex acquisition, the Partnership had gross capital expenditures of $34 million in 2003, of which $1 million was charged to joint-venture partners of the Younger and Joffre plants.

Equity

At year-end 2003, Taylor had 18,005,763 limited partnership units outstanding compared to 9,722,713 at year-end 2002. The increase was primarily the result of 8,250,000 limited partnership units being issued through the public offering which closed on October 17, 2003. The offering raised $42 million, net of costs,

which was used to fully repay the bridge loan arranged to finance the acquisition of the RET Complex and to retire a portion of the remaining debt.

At year-end 2003, the Partnership had options outstanding to purchase 523,750 (2002 – 524,550) limited partnership units at prices ranging from $3.75 to $5.98 per unit. Of this amount, 463,375 (2002 – 497,050) were exercisable.

Minority Interest in Partnership

Minority interest in the Partnership did not change significantly during 2003, ending the year at a balance of $9.2 million. The minority interest in Taylor is comprised of limited partners that hold Taylor Gas Liquids Limited Partnership expansion units. These units are entitled to fund 26.75 percent of capital expenditures incurred by the Partnership at the Younger Plant.

Financial Position

The following table outlines significant changes in the consolidated balance sheets that occurred between December 31, 2003 and December 31, 2002:

(In thousands of Canadian dollars)

	Increase (Decrease)	Explanation
Cash and cash equivalents	(207)	Refer to Consolidated Statements of Cash Flow
Capital assets	28,535	Acquisition of RET Complex in September 2003 and capital additions at Younger and Joffre plants, less depreciation of each facility during the period.
Unitholders' distributions payable	1,159	Increase due to 8 million limited partnership units being issued during 2003 and additional cash generated from operations as a result of the inclusion of the Joffre Plant and the RET Complex.
Advance from joint-venture partner	(1,125)	Combined current and long-term portion was reduced due to meeting the contractual requirements required to earn the performance-based payment.
Long-term debt	(12,029)	Decrease resulted from applying a portion of 2003 equity offering proceeds against existing debt.
Unitholders' equity	38,866	Increase due to Partnership unit offering of October 17, 2003 which raised net proceeds of $42 million, plus net income less unitholders' distributions declared.

Liquidity and Capital Resources

The following table summarizes changes in cash flow for the year ended December 31, 2003 compared to the same period ended December 31, 2002:

(In thousands of Canadian dollars)	2003	2002	Explanation
Cash, beginning of period	4,438	1,263	
Cash provided by (used in):			
Operating activities	12,117	(1,394)	During 2003, the Joffre Plant began operations, resulting in increased income and associated trade payables to fund ongoing operations; RET Complex operations were included as of September 2003. In addition, accounts receivable balances were reduced upon the receipt of insurance settlement proceeds in January 2003.
Financing activities	26,031	16,696	During 2003, net cash was primarily provided by the public offering that raised \$42.4 million. Proceeds were used for the RET Complex acquisition and to reduce long-term debt which subsequently triggered a realized foreign exchange gain of \$1.7 million, for a total debt reduction of \$10.3 million. Net cash from the above activities was reduced by \$6.1 million in cash distributions. During 2002, net cash was predominantly from draws on the new debt facility for the construction of the Joffre Plant for \$18.9 million, a construction advance of \$1.5 million and net limited partner contributions of \$0.7 million, less cash distributions of \$4.3 million.
Investing activities	(38,272)	(12,127)	During 2003, the reduction in net cash was the result of the acquisition of the RET Complex in September 2003 plus accounts payable payments relating to Joffre Plant construction. Net cash was also reduced by capital expenditures at the Younger and Joffre plants, net of joint-venture partners' share of these same expenditures. In 2002, the Younger and Joffre plants had net expenditures of \$17.8 million, less the use of \$5.6 million in working capital.
Effect of exchange rate changes on cash	(83)	–	Unrealized foreign exchange loss on U.S.-dollar denominated cash balances.
Cash, end of period	$ 4,231	4,438	

Working Capital and Cash Requirements

At year-end 2003 the Partnership's working capital was $0.9 million compared to $3.9 million in 2002. Due to the the terms of the Partnership's commercial contracts, the timing of cash collection occurs simultaneously with cash payments, thereby minimizing the Partnership's requirement to maintain a significant working capital position. Any timing differences, whether short or long-term, are managed through the use of working capital or existing debt facilities.

With the exception of those items disclosed, there are no known trends, events or uncertainties to indicate any impairment in the sources or uses of cash that would have a material effect on the financial condition of the Partnership.

Commitments and Guarantees

The Partnership has assumed various commitments, guarantees and contractual obligations in the normal course of its operations. At December 31, 2003, obligations representing known future cash payments that are required under existing contractual arrangements are $0.9 million over the next three years. In addition, the Partnership has a commitment to reduce sulphur emissions at the RET Complex by August 1, 2004. The capital investment necessary to meet this commitment is approximately $4.0 million, net to the Partnership, which will be financed through the revolving credit facility, described below. Costs for this project will be recovered over time from the processing fees collected from RET Complex customers following completion of the project.

The Partnership has issued a guarantee to indemnify the vendor of the RET Complex with respect to potential third-party claims, such as environmental and tax, associated with the acquisition. Due to the nature of the indemnifications, the maximum exposure under the agreement cannot be estimated. As at December 31, 2003 management has not been notified of any claims.

Debt Facilities

On January 14, 2004 the Term Facility and the Younger Capital Project Facility were refinanced into a $26 million revolving credit facility with an extendible 364-day revolving period and a $2 million reducing term facility (collectively the "New Facilities"). The New Facilities bear interest at banker's acceptance rates plus stamping fees plus applicable margins. The margins and stamping fees vary depending on financial statement ratios and can range from 1.25-2.00 percent.

The revolving credit facility is subject to renewal on May 31, 2004 at which time it can be extended at the lender's option for 364 days. If the revolving credit facility is not extended, the amount drawn is fully repayable on May 31, 2005. The reducing term facility is repayable in equal quarterly installments over a 14-year period commencing March 31, 2004. Each repayment results in a corresponding increase in the amount available under the revolving credit facility. The total amount available at any time under the New Facilities is $28 million. The New Facilities are secured by a first fixed and floating charge debenture on all of the Partnership's assets.

The Partnership also maintains a $7.5 million operating facility, reduced by outstanding letters of credit, of $0.9 million that bears interest at the bank's prime lending rate plus margins ranging from 0.25-1.07 percent, depending on financial statement ratios.

Financing Activities

In support of the Partnership's stated objective of growth, the Partnership may issue additional units or borrow funds in the future to finance the Partnership's capital expenditure requirements, acquisitions or for other reasons.

Risk Factors

Business Risks

The Partnership's natural gas liquids extraction, natural gas processing and marketing operations are exposed to a number of business risks that can significantly affect financial results. These include internal risks such as operational and production risks and external factors such as fluctuations in commodity prices, foreign exchange and interest rates, government regulations and taxes, transportation and marketing constraints and environmental and safety concerns. The Partnership has actively structured business arrangements to mitigate the effect of certain risks on the Partnership's income and distributions. These include long-term marketing agreements with EnCana Corporation for Younger Plant production and with NOVA Chemicals Corporation for Joffre Plant production.

Commodity Price

The Partnership has diversified its income from operations by developing return-on-capital-derived fixed fee, fee-for-service and performance-based profit share income. The fixed-fee income is related to capital spent, whereas fee-for-service income and profit share income are sensitive to the volume produced or processed and operating expenses incurred.

The Joffre Plant has been designed to allow the selective rejection of either ethane or C_3^+. If C_3^+ margins are poor, the Joffre Plant can simply not recover the product, and thereby not incur the associated feedstock costs. Similarly, if NOVA does not require ethane, the Joffre Plant can leave the ethane in the natural gas stream, and continue to extract C_3^+, with no effect on the fixed fee received from NOVA Chemicals Corporation.

Operational Matters and Hazards

The Partnership's operations are subject to common hazards of natural gas processing. The operation of the Partnership's natural gas liquids extraction plants, natural gas processing plants, pipelines and other facilities could be disrupted by natural disasters or other events beyond the control of the Partnership. A casualty occurrence could result in the loss of equipment or life, as well as injury and property damage. The Partnership carries insurance coverage with respect to some, but not all, casualty occurrences in amounts customary for similar business operations. This coverage may not be sufficient to compensate for all casualty occurrences.

The operation of the Partnership's natural gas liquids extraction plants, natural gas processing plants, pipelines and other facilities involves many risks. These include:

- the breakdown or failure of equipment, information systems or processes;
- the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects);
- failure to maintain an adequate inventory of supplies or spare parts;
- operator error;
- labour disputes;
- disputes with owners of interconnected facilities and carriers; and
- catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the Partnership.

The occurrence or continuance of any of these events could increase the cost of operating the Partnership's facilities and/or reduce its processing or throughput capacity, thereby reducing revenue.

Credit Risk

A significant portion of revenue from the Younger Extraction Plant is received from a single customer, EnCana Corporation, under the Natural Gas Liquids Purchase Agreement. Similarly, a significant portion of

revenue from the Joffre Extraction Plant is received from a single customer, NOVA Chemicals Corporation, under the Ethane Supply Agreement. The remaining portion of the Partnership's accounts receivable are with joint-venture partners in the oil and natural gas industry and are subject to normal industry credit risks.

Interest Rates

Interest rates are currently at historically low levels. An increase in interest rates will increase the Partnership's borrowing expense and reduce the amount of cash available for distributions. These increases will be partially offset because higher interest rates result in increased return-on-capital-derived fixed payments to the Partnership under both the Natural Gas Liquids Purchase Agreement and the Ethane Supply Agreement.

Foreign Exchange

The Partnership is exposed to foreign currency fluctuations because the return-on-capital charge revenue that is paid to the Partnership under the Natural Gas Liquids Purchase Agreement is paid in U.S. dollars. In addition, natural gas liquids prices are generally based on a U.S. dollar market price. Fluctuations in exchange rates between the U.S. and Canadian dollar will therefore give rise to currency exchange exposure.

During the second quarter of 2003, the Partnership entered into a financial instrument that minimizes the negative impact of a strengthening Canadian dollar on distributions to unitholders. This financial instrument was structured to protect a portion of the U.S.-denominated revenue in excess of U.S.-denominated interest from increases in the value of the Canadian dollar beyond US$0.75, or Cdn$1.33, to year-end 2003. The financial instrument, called a costless collar, allows the Partnership to receive Canadian dollars in exchange for U.S. dollar revenue at a rate no less than $1.33. On the other hand, if the Canadian dollar weakens below US$0.72, or Cdn$1.38, then the Partnership will receive $1.38 for its U.S. dollar revenue. As a result, the Partnership has banded its exchange rate exposure between a 'floor' and a 'ceiling'.

Subsequent to year-end 2003, the Partnership extended the above financial instrument for the calendar year 2004 under terms that allow the Partnership to receive Canadian dollars in exchange for essentially all of its U.S. dollar revenue at a rate no less than $1.31 or US$0.76. On the other hand, if the Canadian dollar weakens below US$0.74, or Cdn$1.36, then the Partnership will receive $1.36 for its U.S. dollar revenue. The Partnership does not use financial instruments for trading purposes.

Management's Report to the Unitholders

Taylor Gas Liquids Ltd., as general partner of Taylor NGL Limited Partnership, is responsible for the preparation of the financial statements and for the consistency therewith of all other financial and operating data presented in this annual report. The financial statements have been prepared in accordance with the accounting policies summarized in the accounting policies' note. The financial statements are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances and have been prepared within acceptable limits of materiality. The financial information contained elsewhere in the annual report has been reviewed to ensure consistency with that in the financial statements. Management maintains a system of internal accounting controls in order to provide reasonable assurance as to the reliability of the financial records and the safeguarding of assets. External auditors have examined the financial statements and have expressed their opinion on the statements. Their report is included with the financial statements. The Audit Committee of the Board of Directors, which is comprised of three independent directors, has discussed the financial statements with management and the external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Robert J. Pritchard
President and
Chief Executive Officer
January 21, 2004

Barry O'Brien
Secretary and
Chief Financial Officer

Auditors' Report to the Unitholders

We have audited the consolidated balance sheets of Taylor NGL Limited Partnership as at December 31, 2003 and 2002 and the consolidated statements of income and unitholders' equity and cash flow for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada

January 23, 2004

Consolidated Balance Sheets

As at December 31, (Stated in thousands of dollars)	2003	2002
ASSETS:		
Current assets:		
Cash and cash equivalents	$ 4,231	$ 4,438
Accounts receivable (note 3)	8,992	9,269
Prepaid expenses and interest	32	190
Due from Manager (note 9)	–	579
	13,255	14,476
Capital assets (note 4)	140,951	112,416
	$ 154,206	$ 126,892
LIABILITIES AND UNITHOLDERS' EQUITY:		
Current liabilities:		
Accounts payable and accrued liabilities	$ 9,064	$ 8,920
Unitholders' distributions payable	2,520	1,361
Due to limited partners (note 10)	282	332
Due to Manager (note 9)	104	–
Advance from joint-venture partner (note 4)	375	–
	12,345	10,613
Long-term debt (note 5)	20,000	32,029
Advance from joint-venture partner (note 4)	–	1,500
Site restoration provision	245	–
Minority interest in Partnership (note 1)	9,218	9,218
	41,808	53,360
Unitholders' equity (note 6)	112,398	73,532
Insurance claims and contingencies (note 3)		
Commitments (note 11)		
	$ 154,206	$ 126,892

See accompanying notes to consolidated financial statements.

Approved by the Board:

Robert R. Andrews
Director

Robert J. Pritchard
Director

Consolidated Statement of Income and Unitholders' Equity

Years ended December 31, (Stated in thousands of dollars except unit amounts)	2003	2002
REVENUE:		
Natural gas liquids sales	$ 105,573	$ 77,953
Fee income	10,054	6,993
Other	522	141
	116,149	85,087
EXPENSES:		
Shrinkage gas	88,368	64,957
Operating costs	15,910	12,173
Administration (note 9)	810	9
Depreciation and site restoration	3,980	2,663
Interest	1,556	385
Realized foreign exchange gain (note 6)	(1,232)	–
Unrealized foreign exchange loss (gain)	83	(68)
	109,475	80,119
Income before the following	6,674	4,968
Management fees (note 9)	(253)	(240)
Overhead recovery fees (note 9)	(1,536)	(1,729)
Distributions to limited partners (note 10)	(1,311)	(1,461)
Insurance recovery (note 3)	–	2,562
Net income	3,574	4,100
Unitholders' equity, beginning of period	73,532	73,807
Units issued, net of issue costs (note 6)	42,503	–
Unitholders' distributions declared	(7,211)	(4,375)
Unitholders' equity, end of period	$ 112,398	$ 73,532
Net income per Partnership unit:		
Basic	$ 0.31	$ 0.42
Diluted	$ 0.31	$ 0.42
Weighted average Partnership units outstanding:		
Basic	11,491,985	9,722,713
Diluted	11,554,475	9,766,349

See accompanying notes to consolidated financial statements.

Consolidated Statement of Cash Flow

Years ended December 31, (Stated in thousands of dollars)	2003	2002
CASH PROVIDED (USED IN):		
OPERATIONS:		
Net income	$ 3,574	$ 4,100
Depreciation and site restoration	3,980	2,663
Unrealized foreign exchange loss (gain)	83	(68)
Realized foreign exchange gain on U.S.-dollar debt	(1,658)	–
Other	(375)	–
	5,604	6,695
Change in non-cash working capital (note 13)	6,513	(8,089)
	12,117	(1,394)
FINANCING:		
Units issued for cash, net of issue costs	42,503	–
Long-term debt	(10,371)	18,906
Unitholders' distributions paid	(6,052)	(4,278)
Due to limited partners	(50)	(83)
Limited partner contributions	1	651
Advance from joint-venture partner	–	1,500
	26,031	16,696
INVESTMENTS:		
Acquisition (note 4)	(31,576)	–
Change in non-cash investing working capital (note 13)	(5,252)	5,646
Capital expenditures	(2,233)	(38,174)
Reimbursement of capital by joint-venture partners (note 4)	789	20,401
	(38,272)	(12,127)
Effect of exchange rate changes on cash	(83)	–
Change in cash and cash equivalents	(207)	3,175
Cash and cash equivalents, beginning of period	4,438	1,263
Cash and cash equivalents, end of period	$ 4,231	$ 4,438

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2003 and 2002
(Tabular amounts are stated in thousands of dollars except unit amounts)

1. ORGANIZATION

The Taylor NGL Limited Partnership (the "Partnership") was formed on August 16, 2000 whereby the Partnership became the sole holder of Base Partnership Units and Class C Expansion Units of the Taylor Gas Liquids Limited Partnership ("TGLLP"), which has an interest in the Younger Extraction Plant (the "Younger Plant") located at Taylor, British Columbia. Previously, the Partnership was an unincorporated Trust, Taylor Gas Liquids Fund (the "Fund"), which was formed under the laws of the Province of Alberta pursuant to a Trust indenture dated May 15, 1996. The general partner of the Partnership is Taylor Gas Liquids Ltd. ("General Partner"), while the public holds the Partnership Units (the "Units").

On December 31, 2001 Joffre Gas Liquids Limited Partnership ("JGLLP") was formed to be the holder of the Partnership's 50 percent interest in the Joffre Ethane Extraction Plant (the "Joffre Plant"). The Partnership owns 99.99 percent of JGLLP.

On September 4, 2003, Taylor Gas Processing Limited Partnership ("TGPLP") acquired an interest in the Retlaw, Enchant and Turin gas processing plants and related gathering systems located near Lethbridge, Alberta (collectively the "RET Complex"). The Partnership owns 99.99 percent of TGPLP.

The general partner of TGLLP, JGLLP and TGPLP is Taylor Operations Company Inc. ("TOCI"), a wholly-owned subsidiary of Taylor Management Company Inc. ("TMCI" or the "Manager"). TOCI has 0.01 percent partnership interest in TGLLP and owns 0.01 percent of JGLLP and TGPLP.

Under a five-year term, effective January 1, 2001, TMCI is entitled to a management fee equal to 2.75 percent of net revenues of the Partnership and a performance compensation fee if distributable cash of the Partnership exceeds 70 cents per unit per year. In addition, TMCI is entitled to the overhead charges recovered by TGLLP, JGLLP and TGPLP under the marketing and related agreements, net of administration costs incurred by TMCI, with any difference being billed or transferred to the Partnership.

The limited partners of TGLLP include the Partnership, TMCI and other non-related parties. The limited partners of TGLLP, other than the Partnership, are entitled to the portion of the distributions attributable to

26.75 percent of production in excess of the estimated plant capacity as at the time of the acquisition of the Younger Plant by the Fund. In addition, limited partners, other than the Partnership, have the option to contribute capital equal to 26.75 percent of any future capital expenditures of the TGLLP in return for distributions equal to the associated recovery of capital earned by the TGLLP.

In accordance with the terms of the partnership agreement and related agreements, cash not required for the business of the TGLLP, JGLLP and TGPLP will be distributed to the Partnership on a quarterly basis, which in turn will distribute to the unitholders of the Partnership.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation

These consolidated financial statements include the accounts of the TGLLP, JGLLP, TGPLP, the General Partner and the Fund.

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts. These estimates are subject to uncertainty and may impact financial statements of future periods.

(b) Revenue

All natural gas liquids ("NGLs") produced by TGLLP at the Younger Plant are sold at the outlet of the plant under a long-term marketing agreement (the "NGL Purchase Agreement") with EnCana Corporation ("EnCana"). Pursuant to the terms of the NGL Purchase Agreement, TGLLP's revenue is based on a return on capital, recovery of operating costs and natural gas costs and a 50-percent share of the proceeds received from the final sale of NGLs by EnCana, net of all costs. If the proceeds on the sale of NGLs do not exceed the return on capital and operating and natural gas costs, then future proceeds will only accrue to TGLLP after the retirement of this deficiency. As at December 31, 2003, TGLLP's 50-percent share of this deficiency was estimated to be $3.0 million (2002 – $1.6 million).

If the deficiency is greater than $1.75 million gross at two consecutive calendar year-ends, EnCana has the right to terminate the NGL Purchase Agreement by giving notice to the Partnership during the first 60 days of the following calendar year. If EnCana exercises this option, it must pay the Partnership an amount equal to the sum of all of the capital that the Partnership has invested in the Younger Plant, less cumulative depreciation, as defined in the NGL Purchase Agreement. The amount payable to the Partnership is estimated by Management

to be approximately US $17.5 million as at December 31, 2003. The aggregate deficiency has in the past been and is now such that EnCana would, during the first 60 days of 2004, have the right to terminate the NGL Purchase Agreement. Management does not currently believe and has not received any indication from EnCana that they will exercise this right.

The Partnership began operations of the Joffre Plant in the first quarter of 2003. The Joffre Plant is jointly owned by the Partnership (50 percent) and AltaGas Services Inc. ("AltaGas") (50 percent). The ethane produced at the Joffre Plant is sold at the outlet of the plant under a long-term sales agreement (the "Ethane Supply Agreement") with NOVA Chemicals Corporation ("NOVA Chemicals"). Pursuant to the terms of the Ethane Supply Agreement, the sales price is based on a return on capital charge and a recovery of the operating costs attributed to the production of ethane. The remaining NGLs ("Propane-Plus") produced at the Joffre Plant are sold into the Alberta market at prevailing prices. The Partnership's share of revenue received under the Ethane Supply Agreement and sale of Propane-Plus is included in NGL sales.

Shrinkage costs associated with the Partnership's share of Propane-Plus from the Joffre Plant are included in expenses as shrinkage gas. The Partnership's share of Joffre Plant operating costs is included as expenses.

Revenue for processing services at the RET Complex is recorded as the services are rendered. Processing fees that are a function of volumes processed are recognized in the period in which the processing occurs. Fees which are not directly related to volumes processed, such as capital recovery, are recognized at stipulated rates over the contract periods. Fees derived from the recovery of operating expenses are recognized in the period in which the expenses are incurred.

(c) Capital assets

The Younger Plant is depreciated over a 40-year period, commencing July 1, 1996, using the straight-line method of depreciation. The Joffre Plant uses the same method of depreciation which began with commercial operations in January 2003.

The RET Complex is depreciated over a 25-year period using the straight-line method. Amortization of the intangible assets is provided for on a straight-line basis over three years.

Capital assets are recorded at cost. Repairs and maintenance costs are expensed in the period incurred.

In accordance with various agreements, TGLLP is party to indemnities with respect to future site restoration and reclamation costs at the Younger Plant. Future salvage values are anticipated by management to be in excess of future site restoration and reclamation costs.

(d) Income taxes

Pursuant to the August 16, 2000 restructuring of the Fund to a limited partnership, the income of the Partnership is taxed at the partner level. As a result, provision for income and capital taxes is the responsibility of the limited partners.

(e) Partnership unit-based compensation plan

Commencing January 1, 2002, for options or similar instruments granted to non-employees, an amount equal to the grant date fair value, if any, will be recorded as a cost over the vesting period. For options granted to employees of the Partnership, the standard provides that the Partnership may elect not to use this fair value method but to disclose the impact of the fair value method on a pro-forma basis. The fair value of the options granted since January 1, 2002 had no significant impact to the financial statements for the years ended December 31, 2003 and 2002.

(f) Foreign currency

The Partnership translates its monetary and non-monetary foreign currency balances using year-end rates. Transactions in foreign currencies during the year are recorded at the exchange rate in effect on that date. Foreign exchange gains and losses are included in income.

(g) Cash and cash equivalents

The Partnership considers cash and short-term deposits with maturities of three months or less as cash and cash equivalents.

3. INSURANCE CLAIMS AND CONTINGENCIES

In January 1999, an incident caused the Younger Plant to be shut down for approximately one year. The Partnership submitted claims and drew funds from its insurers to meet the Younger Plant reconstruction costs and replace profits which would have been generated by the Younger Plant if normal operations had continued uninterrupted. The owners of the Younger Plant reached a settlement with the insurers in December 2002 that resolved the balance of the claims submitted for property reconstruction and business interruption. In December 2002, $2,595,636 was collected from other Younger Plant owners and $1,939,645 was collected from the insurers during January 2003, in respect of the claim settlement.

During 1999, $2,352,211 of the amount claimed under the business interruption coverage was included as deferred revenue. As a result of the settlement, this amount was included in net income for the year ended December 31, 2002, including additional recoveries for a total of $2,561,699.

The Partnership has been named, along with certain other parties, in lawsuits for losses incurred as a result of the Younger Plant shutdown in 1999. Management believes that the claimants will not be successful. In the event that a third-party liability claim is successful, the Partnership's liability insurance is sufficient to cover the Partnership's portion of such claim.

4. CAPITAL ASSETS

	2003	2002
Younger and Joffre Plants and RET Complex	$ 159,360	$ 127,857
Accumulated depreciation	(19,271)	(15,441)
	140,089	112,416
Intangible assets, net of accumulated amortization of $138,000	862	–
	$ 140,951	$ 112,416

Interest in the amount of $118,000 (2002 – $721,000) was capitalized during the year.

Under a joint-venture agreement, JGLLP and AltaGas each own 50 percent of the Joffre Plant. AltaGas has reimbursed JGLLP for 50 percent of the costs to complete the Joffre Plant and subsequent additions. As part of this reimbursement, AltaGas paid $1.5 million to JGLLP, subject to repayment under certain conditions relating to the completion of construction and commercial operations of the Joffre Plant. As of December 31, 2003, certain conditions have been met, resulting in $375,000 being recognized as revenue and $750,000 as a reduction to capital assets. While management believes that the remaining conditions will be met, the balance of $375,000 has been recorded as an advance as at December 31, 2003 (2002 – $1.5 million).

On September 4, 2003, the Partnership acquired the RET Complex for cash consideration of $31,576,000, including transaction costs of $1,076,000. The acquisition is summarized as follows:

Capital assets	$ 30,816
Intangible assets	1,000
Site restoration provision	(240)
	$ 31,576

The acquisition was financed by a $30.5 million bridge loan facility that bore interest at the prime rate plus 1 percent. The facility was repaid from the October 17, 2003 Partnership Unit offering.

5. LONG-TERM DEBT

	2003	2002
Term facility	$ 20,000	$ 31,361
Younger Capital Project Facility	–	668
	$ 20,000	$ 32,029

At December 31, 2003 $20,000,000 (2002 – $31,362,000) was drawn on the syndicated term facility ("Term Facility"), with interest payable at banker's acceptance rates plus stamping fees plus applicable margins. As at December 31, 2003, the banker's acceptance rate for the Term Facility was 2.78 percent while the margins and stamping fees totalled 2.00 percent.

On January 14, 2004, the Term Facility and the Younger Capital Project Facility were refinanced into a $26 million revolving credit facility with an extendible 364-day revolving period and a $2 million reducing term facility (collectively the "New Facilities"). The New Facilities bear interest at banker's acceptance rates plus stamping fees plus applicable margins. The margins and stamping fees vary depending on financial statement ratios and can range from 1.25 percent to 2.00 percent.

The revolving credit facility is subject to renewal on May 31, 2004 at which time it can be extended at the lender's option for 364 days. If the revolving credit facility is not extended, the amount drawn is fully repayable on May 31, 2005. The reducing term facility is repayable in equal quarterly installments over a 14-year period commencing March 31, 2004, with each repayment resulting in a corresponding increase in the amount available under the revolving credit facility. At any time the total amount available under the New Facilities will be $28 million.

The New Facilities are secured by a first fixed and floating charge debenture on all of the Partnership's assets.

The Partnership also maintains a $7.5 million operating facility, reduced by outstanding letters of credit of $0.9 million, that bears interest at the bank's prime lending rate plus margins ranging from 0.25 percent to 1.07 percent, depending on financial statement ratios.

6. UNITHOLDERS' EQUITY

(a) Authorized

Unlimited Partnership Units

(b) Issued

	Number of Units	Amount
Balance, December 31, 2001	9,722,713	$ 73,807
Net income for the year		4,100
Unitholders' distributions		(4,375)
Balance, December 31, 2002	9,722,713	73,532
Net income for the year		3,574
Unitholders' distributions		(7,211)
Units issued on exercise of options	33,050	125
Units issued on offering of October 17, 2003	8,250,000	44,963
Issue expenses		(2,585)
Balance, December 31, 2003	18,005,763	$ 112,398

On October 17, 2003, the Partnership closed an equity offering of 8,250,000 Partnership Units at a price of $5.45 per unit, for gross proceeds of $44,963,000 or net proceeds of $42,378,000 after offering expenses of $2,585,000. The proceeds of this offering were used to repay the bridge loan facility that was incurred to fund the September 4, 2003 acquisition of the RET Complex. The remaining proceeds were used to repay the Partnership's existing U.S.-denominated bank debt. The repayment of the U.S.-denominated bank debt resulted in a foreign exchange gain of $1,658,000, offset by a foreign exchange loss of $426,000 on U.S.-denominated cash that was held by the Partnership.

(c) The limited partners of TGLLP, other than the Partnership, are entitled to exchange their TGLLP Units for that number of Partnership Units which had the same aggregate cash entitlement over the preceding four quarters as the aggregate cash distributions received by them as TGLLP Partners. During the years ended December 31, 2003 and 2002, none of the limited partners exercised this right.

7. PARTNERSHIP UNIT OPTION PLAN

A Partnership Unit option plan provides for the issuance of options to acquire units to employees and directors of the General Partner, excluding management. The number of units reserved is limited to 783,650. The options expire at various dates to December 9, 2008.

The following tables summarize information about Partnership Unit options as at December 31, 2003 and 2002:

	2003		2002	
	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, beginning of year	524,550	$ 4.73	608,150	$ 5.95
Granted	109,750	5.36	22,500	4.34
Exercised	(33,050)	3.77	–	–
Expired	(77,500)	5.71	(106,100)	11.64
Outstanding, end of year	523,750	$ 4.78	524,550	$ 4.73
Exercisable, end of year	463,375	$ 4.66	497,050	$ 4.75

Exercise Price	Number Outstanding	Number Exercisable	Weighted Average Remaining Life (years)
$ 3.75	2,750	2,750	0.9
4.34	21,250	10,625	3.9
4.40	10,000	10,000	3.0
4.65	380,000	380,000	2.1
4.85	60,000	60,000	4.4
5.98	49,750	–	4.9
$ 3.75 to $5.98	523,750	463,375	2.7

8. PENSION PLAN

The Partnership has a defined benefit pension plan which covers Younger Plant employees represented by a union with which the Partnership has a collective bargaining agreement. The plan provides pensions based on length of service and the highest consecutive three years' average earnings.

As at December 31, 2003, the market value of the assets of the Plan was $1,415,000 (2002 – $1,072,600). The estimated actuarial present value of the associated liabilities as at December 31, 2003 was $1,249,400 (2002 – $1,064,900). The significant actuarial assumptions, adopted in measuring the accrued benefit obligations for 2003, was a discount rate of 6.5 percent (2002 – 7.0 percent), expected long-term rate of return on plan assets of 6.5 percent (2002 – 7.0 percent) and a rate of compensation increase of 4.0 percent (2002 – 4.5 percent).

The employer's contributions to the plan during the year ended December 31, 2003 were $111,900 (2002 – $115,600) and benefits paid during 2003 were $10,200 (2002 – $10,600).

9. MANAGEMENT FEES AND OVERHEAD RECOVERIES PAID TO MANAGER

For the year ended December 31, 2003 the management fee and overhead recoveries paid to the Manager were $253,000 (2002 – $240,000) and $1,536,000 (2002 – $1,729,000), respectively.

Pursuant to the 2001 Administration Agreement between the Manager, the General Partner and the Partnership, in the event that overhead recoveries paid to the Manager are in excess of administration costs of the Manager, the excess recoveries are payable back to the Partnership. Subject to the same agreement, in the event that administration costs of the Manager are in excess of overhead recoveries, the excess costs are payable by the Partnership to the Manager. Excess recoveries payable to the Partnership by the Manager or additional costs payable by the Partnership to the Manager are applied to the Partnership's administration expenses.

For the year ended December 31, 2003 the overhead recoveries paid to the Manager exceeded the administration costs of the Manager by $165,000 (2002 – $1,000,000). Hence, administration expenses of the Partnership were reduced during 2003, for a net administration expense of $810,000 (2002 – $9,000). Management fee and overhead recoveries, less the above noted excess of $165,000, due to the Manager from the Partnership as at December 31, 2003 was $104,000 (2002 – Manager owed the Partnership $579,000).

10. DISTRIBUTIONS TO LIMITED PARTNERS

Distributions to the limited partners of TGLLP, other than the Partnership, for the year ended December 31, 2003 were $1,311,000 (2002 – $1,461,000).

As at December 31, 2003, the $282,000 (2002 – $332,000) due to the limited partners of TGLLP relates to their distributions owing, net of contributions owing for capital expenditures of the TGLLP.

11. COMMITMENTS

The Partnership is committed to various lease payments for office space, vehicles and office equipment. Under the terms of the leases, the following future payments are required:

2004	$ 571
2005	245
2006	103
	$ 919

As at December 31, 2003, future minimum lease payments for land use associated with the Joffre Plant were $15,000 for each of the years 2004 through 2033.

The Partnership has a commitment to reduce sulphur emissions at the RET Complex by August 1, 2004. The capital investment necessary to meet this commitment is approximately $4.0 million, net to the Partnership, of which $150,000 gross has been incurred to date. Costs for this project will be recovered over time from the processing fees collected from RET Complex customers following the completion of the project.

12. FINANCIAL INSTRUMENTS

Interest rate risk

As at December 31, 2003 the Partnership was exposed to floating interest rates with respect to its long-term debt and had no fixed interest rate borrowings extending beyond one year. Sustained increases in interest rates would be offset by related increases in revenue under the terms of the NGL Purchase Agreement and Ethane Supply Agreement.

Foreign currency risk

The Partnership uses financial instruments to hedge a portion of its exposure to foreign exchange fluctuations. The Partnership does not use financial instruments for trading purposes.

The Partnership is exposed to foreign currency fluctuations as TGLLP receives U.S. dollars as part of its revenue under the NGL Purchase Agreement. The Partnership fixed the exchange rate on the U.S. dollar-denominated revenue stream by entering into a costless collar setting the exchange rate on $230,000 U.S. dollars per month at a rate of $0.735 to $0.763 U.S. per Canadian dollar. The contract commenced in January 2004 and expires on December 27, 2004. At December 31, 2003, the fair value of the costless collar was not significant.

Credit risk

A significant portion of revenue from the Younger Plant is received from a single customer, EnCana, under the NGL Purchase Agreement and a significant portion of revenue from the Joffre Plant is received from a single customer, NOVA Chemicals, under the Ethane Supply Agreement.

The RET Complex has credit exposure to a number of customers in the oil and gas industry under its operating and processing arrangements. These amounts are subject to normal industry credit risks.

Fair value of financial instruments

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, due to/from the Manager, due to limited partners and advance from joint venture partner approximate their fair values due to the near term nature of these financial instruments. The carrying value of long-term debt approximates fair value as it bears floating interest rates.

13. SUPPLEMENTARY CASH FLOW INFORMATION

The change in non-cash working capital from operations was comprised of:

	2003	2002
Accounts receivable	$ 1,811	$ 647
Accounts payable and accrued liabilities	3,958	(5,147)
Prepaid expenses	61	(93)
Payable to manager	683	(1,144)
Deferred revenue	–	(2,352)
	$ 6,513	$ (8,089)

The change in non-cash working capital from investments was comprised of:

	2003	2002
Accounts receivable	$ (1,533)	$ 1,534
Accounts payable and accrued liabilities	(3,816)	4,209
Prepaid expenses	97	(97)
	$ (5,252)	$ 5,646

Cash interest paid for the year ended December 31, 2003 was $1,708,000 (2002 – $883,000).

14. GUARANTEES

The Partnership has entered into an agreement indemnifying a certain party with respect to potential third-party claims, such as environmental and tax, associated with the acquisition of the RET Complex. Due to the nature of the indemnifications, the maximum exposure under the agreement cannot be estimated. As at December 31, 2003 management has not been notified of any claims.

Corporate Governance

The general partner of Taylor NGL Limited Partnership is Taylor Gas Liquids Ltd., which is governed by a Board of Directors. The Board of Directors has ultimate responsibility for the management of the Partnership including the development of a strategic plan, identifying and controlling the principal risks of the Partnership, developing communications, policies and internal control and management systems. The Board has seven directors. Six were nominated by the unitholders, and Taylor Management Company Inc. nominated the remaining director. In 2001 the Board convened an Audit Committee. The Committee has adopted a charter that clearly defines its responsibilities in the areas of external audit, internal controls, governance and financial reporting. The Board does not have a compensation committee or a nominating committee – the entire Board addresses matters in these areas. The general partner of the Partnership has entered into an Administrative Agreement with Taylor Management Company Inc. to provide management and administrative services. Taylor Management Company Inc. is reimbursed for actual costs incurred in performing these duties plus a management fee of 2.75 percent of net operating cash flow plus a performance-based fee that is paid if distributable income is greater than $0.70 per unit annually. There are no acquisition or divestment fees paid to Taylor Management Company Inc.

Corporate Information

Shareholder Information

STOCK EXCHANGE LISTING

Toronto Stock Exchange (Symbol TAY.UN)

Legal Counsel

Macleod Dixon LLP, Calgary, Alberta

Banker

RBC Royal Bank

Canadian Western Bank

Transfer Agent and Trustee

Computershare Trust Company of Canada

Auditors

KPMG LLP, Calgary, Alberta

Investor Relations

2200, 800-5th Avenue S.W.

Calgary, Alberta T2P 3T6

Tel: (403) 781-8181

Fax: (403) 777-1907

Website

www.taylorngl.com

Officers and Directors

Robert R. Andrews, a director since 1996 and Chairman of the Board since 2003, is an independent businessman. Mr. Andrews resides in Calgary, Alberta.

Ian D. Bruce, a director since 1996, is President and Chief Executive Officer of Peters and Co. Limited, an investment firm that specializes in underwriting and advisory services for the oil and gas industry. Mr. Bruce resides in Calgary, Alberta.

James W. Davie, a director since 2003, has had an extensive career in the investment banking industry and is currently an advisor to and director of several companies. Mr. Davie resides in Toronto, Ontario.

Walentin (Val) Mirosh, a director since May 2003, is currently Vice President, NOVA Chemicals Corporation, and President, Olefins and Feedstock. Mr. Mirosh resides in Calgary, Alberta.

Donald J. Nelson, a director since May 2003, has had an extensive career in the oil and gas industry and is currently an advisor to and director of several energy companies. Mr. Nelson resides in Calgary, Alberta.

Barry O'Brien, is secretary and chief financial officer of Taylor Gas Liquids Ltd. and Taylor Management Company Inc., the manager and administrator of the Partnership. Mr. O'Brien resides in Calgary, Alberta.

Robert J. Pritchard, a director since December 2000, is president and chief executive officer of Taylor Gas Liquids Ltd. and Taylor Management Company Inc., the manager and administrator of the Partnership. Mr. Pritchard resides in Calgary, Alberta.

David J. Schmunk, is chief operating officer of Taylor Gas Liquids Ltd. and Taylor Management Company Inc., the manager and administrator of the Partnership. Mr. Schmunk resides in Cochrane, Alberta.

Kenneth D. Taylor, a director since 1996, is chairman of Global Public Affairs Inc. in Ottawa and New York. Mr. Taylor resides in New York, New York.

Glossary

bbl	barrel
bbls/day	barrels per day
C_2	ethane
C_3	propane
C_4	butane
C_2^+	mixture of ethane, propane, butane and condensate
C_3^+	mixture of propane, butane and condensate
C_5^+	condensate
GJ	gigajoule
mmscf	million standard cubic feet
mmscf/day	million standard cubic feet per day
NGLs	natural gas liquids

Designed and Produced by Merlin Edge Inc.

TAYLOR NGL Limited Partnership
2200, 800-5th Avenue S.W.
Calgary, Alberta T2P 3T6
Tel: (403) 781•8181 **Fax:** (403) 777•1907
www.taylorngl.com